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Energy Procedia 4 (2011) 1909–1916

Energy Procedia

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GHGT-10

Techno-economic assessment of future-proofing coal plants with post-combustion capture against technology developments

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Abstract

While CCS is demonstrated globally utilities will face a period with fast learning curves for capture technologies. Technology and cost uncertainty is a topic of particular concern for first-movers. For post-combustion capture plants, costs are expected to decrease in the future and improved solvents are likely to become commercially available after the first CCS plants have started operating. . Given that power generation assets are usually paid back over extensive periods of time it is important that, in this context, the first generation of plants and any capture-ready plants can be future-proofed to incorporate future technological improvements. This paper presents selected results from a forthcoming report commissioned by the IEAGHG. A methodology based on a sensitivity analysis of solvent properties is used to identify pieces of equipment, which contribute to locking-in performance with capture. Finally, some principles for analysing power plant economics with improved solvents and assessing the potential financial benefits in competitive electricity market of mitigating these technology risks are examined.

Post-combustion; upgradability; solvent; integration

1. Introduction

The IEA forecasts in its BLUE Map scenario that in 2050 55% of the CO_2 being geologically stored worldwide will come from the power sector [1]. This represents 9.4 Gt of CO_2 captured from electricity production using fossil fuels. Given that there is no large scale Carbon Capture and Storage (CCS) project on power generation today, an accelerated demonstration and deployment programme is now required to make CCS a credible technology option for global climate change mitigation by 2020. Both this deployment of initial second-generation reference plants by 2020 and the subsequent rollout from 2020 to 2050 represent challenging build rates for a technology that has not yet been proven at large scale.

In the early stages of CCS deployment, post-combustion capture is expected to play an important role since it does not require extensive modifications to equipment in place or to operating practices. While a commercial-scale CCS demonstration programme is carried out over the next decade, the concept of implementing `carbon capture-ready'

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doi:10.1016/j.egypro.2011.02.070

(CCR) plants has been proposed to ensure that plants constructed now and in the future can be retrofitted at a feasible cost level, and their carbon emissions abated. The scale and the timing for deploying CCS implies that at least several learning cycles can be expected over each of the next few decades and that CCR plants and CCS demonstration projects built during that time will face a subsequent operating period with fast learning curves for capture technologies. Technological uncertainty is therefore a critical issue for the first generation of CCR and CCS plants, given that fossil plants tend to have long operating lives and are unlikely eventually to be using exactly the technology and/or solvent considered as state-of-the-art at time of commissioning. It is therefore essential that these plants can be future-proofed against technology developments. The main risk is that power plants could become locked in to an unnecessarily low level of performance with capture after improved solvents become available, and turn into potential stranded assets. Designing a power generation asset with CCS capable of using a range of capture technologies can mitigate the risks associated with technology change.

Given the present uncertainty in the economics of CCS projects, most of the first generation of CCS plants are likely to receive support from public funding mechanisms. Delivering a CCS infrastructure with power plants locked into first generation capture technologies would not only increase the costs to society of electricity decarbonisation in the long run, but also necessitate the building or retrofitting of as many power generation assets as the number of capture technologies needed to be demonstrated. If investments are made to future-proof the first (and future) CCS plants, this could reduce the number of power generation assets that need to be built, contribute to minimising the cost of electricity decarbonisation through CCS, and also stimulate an open market where power plant owners are not tied in to using the same solvent supplier throughout the plant's lifetime.

This paper focuses on future-proofing coal plants fitted with post-combustion capture using flue gas wet scrubbing with liquid solvents since this technology is likely to be used on many of the first CCS plants and is inherently upgradable through relatively easy replacement of the solvent. The rationales for upgrading the solvent are discussed first. Technical aspects of changing solvent within the constraints of an amine plant, its dedicated CO_2 compression train and the turbine system providing the solvent thermal energy of regeneration are then explored. Finally, some principles for analysing power plant economics with improved solvents are examined. These present (within the space available) selected results from the findings of a study commissioned by the IEAGHG. The reader is referred to a forthcoming IEAGHG report for more information [2].

2. The rationales for upgrading solvents

The implications of changing the solvent used for capture within the constraints of an existing power generation asset attached to a dedicated capture and compression plant are complex. Many possible reasons can justify a solvent upgrade. They can generally be classified in two categories, as outlined in the examples below.

2.1 Keep the plant license to operate by securing compliance with stricter environmental legislation:

- Amine solvent volatility is associated with potentially large environmental impact given the scale of fossil fuel use in electricity production. Limits on emissions to atmosphere of solvents (and their associated degradation products) could tighten over time, especially if more environmentally friendly solvents are developed and demonstrated successfully.
- Reduce specific CO_2 emissions per unit of electricity because of a regulatory requirement to do so, if, for example, an EPS (emissions performance standard) legislation were introduced with a decreasing level of emissions over time. For example, recent analysis shows that average electricity specific emission levels as low as 50 gCO_2 per kWh – equivalent to around 95% capture on a coal unit without the use of biomass co-firing – may be needed by 2030 in the UK [3], and most likely in other economies. This implies that CO_2 transport and storage infrastructure for future-proofed plants may need to be 'oversized' for initial operation so that additional CO_2 export capacity is readily available in the future, possibly within a large scale CO_2 network.

2.2 Improve power plant economics

- Plant capacity and efficiency can be increased by replacing the plant's initial solvent with a solvent resulting in a lower overall electricity output penalty for capture and compression. This would enable the plant owner to recover some of the power necessary for capture, either through steam extraction or ancillary compression power, and so either reduce the cost of electricity generation at the plant or potentially generate additional net plant revenues by increasing the volume of electricity sales. Given the potential for fast learning with CCS technologies, this type of upgrade would also enable first generation plants to compete with newer plants built later with improved solvents. Although efficiency savings would be useful at any plant, the potential to increase power export capacity is likely to be critical in determining how attractive this type of upgrade would be, as discussed below.
- Reduce the other operating costs of the amine plant, such as solvent degradation losses, volatility losses or maintenance costs (corrosion, heat exchanger fouling etc)

- Reduce specific emissions per unit of electricity if economically justified rather than paying for emitting CO_2 (e.g. to anticipate for a change in tax or trading scheme). The CO_2 export capacity is critical here as previously discussed.
- Enhance reliability and availability. Under some circumstances it is also possible that the plant owner would upgrade their solvent to improve flexibility, and thus be able to get additional income through ancillary services from faster response. For example, an inexpensive solvent inventory could be useful for interim storage of solvent between the absorber and the stripper to shift the financial penalty of capture from high to low electricity prices.

Ideally, CCS plants would therefore be capable of operation with a broad range of solvent properties, which capability, as part of a funded demonstration programme, could also facilitate rapid progress through several learning cycles on a single capture and power generation asset with limited support required for additional capital expenditure (in contrast to having to build completely new capture units and/or power plants to demonstrate and deploy new solvents).

3. An integrated approach for the identification and the assessment of performance lock-in

The scope of this paper is limited to the case where a solvent upgrade results in an increase in power plant net electrical output with capture, by reducing the overall electricity output penalty (EOP) of capture and compression at constant fuel input and specific emission level (or constant CO_2 output). Other scenarios are considered in the forthcoming IEAGHG report [2]. The EOP is an appropriate metric to assess capture technologies when expressed on a mass basis (e.g. kWh/tonne CO_2) since it is then independent of the fuel composition, unlike the efficiency penalty. Careful consideration of the overall capture and compression process and power plant (and not just the solvent loop in isolation) is needed to characterise the overall EOP as solvents are changed. The following methodology is, therefore, proposed to identify key pieces of equipment throughout the whole capture process, including steam extraction from the power cycle, the amine plant and the compression train, that may lock-in the EOP of a coal plant to a specific level when its solvent is upgraded and prevent full advantage being taken of the improved solvent properties:

a) The performance of a reference power plant attached to a reference amine plant and a reference compression train operating with a reference solvent is used as a base case for comparison. The reference solvent is taken as a 30%wt MEA solution, with properties based on values taken from the public domain literature (see [2] for more details).

b) A sensitivity analysis of key solvent properties is then performed, with each solvent property adjusted independently of the others. This approach may generate hypothetical combinations of solvent properties that could prove not to represent future solvents, but it has the advantage of covering the possible range of uncertainty facing power plant developers at a time where new solvents are still being actively researched. The four properties that have been adjusted are:

- *Solvent specific heat capacity*, to account for changes in the sensible heat contribution to solvent energy of regeneration during the solvent thermal swing between the absorber and the stripper. A large part of the sensible heat is recovered in the cross-heat exchanger located between the absorber and the stripper while the rest of it comes for condensing steam withdrawn from the steam cycle. The sensible heat contribution is also sensitive to solvent carrying capacity, defined as the difference in solvent loading expressed in mol CO_2 per mol of solvent between the bottom of the absorber and the bottom of the stripper, but this property has not been varied in this analysis since its effects are very similar, with respect to the parts of the process at risk of being locked-in, to those of the solvent energy of regeneration.
- *Solvent thermal stability,* to account for interaction with the steam cycle, notably its ability to supply steam at a range of temperatures, and for its links to changes in solvent energy of regeneration.
- *Overall mass transfer coefficient*, to account for variations in the extent to which CO_2 is transferred from/into the solvent in the absorption and desorption columns. Variations of specific key solvent thermodynamic and transport properties affecting kinetics and mass transfer have not been considered here since they affect the columns in similar ways.
- *Enthalpy of absorption,* to account for interaction between the amine plant and the compression train, notably changes in solvent energy of regeneration, and desorber and compressor train inlet pressure

The resulting EOP is then reported with the assumption that each parametric solvent is used in a dedicated power plant built with a dedicated steam cycle and a dedicated compression train to realistically optimize performance, whilst the amine plant is the reference amine plant of a).

c) Ultimately, the electricity output penalty of each parametric solvent when fitted to the reference power plant, the reference amine plant and the reference compression train of a) is compared to the corresponding solvent of b). This illustrates a situation where a plant is initially commissioned with the reference solvent of a), with no consideration

given to future-proofing, and is then nonetheless upgraded with an improved solvent. The difference in electricity output penalty between b) and c) represents the performance lock-in of the reference plant of a).

Given the space limitations for this article, only the results for the first two solvent properties – specific heat capacity and thermal stability - are covered in the technical discussion below. The reader is referred to the forthcoming report [2] for a full discussion on solvent properties.

4. Description of model

An integrated in-house model has been developed in gPROMs in order to determine the influence of each of these four key solvent properties on the overall EOP of the power plant. It comprises a flowsheet for an amine plant, a separate compression system and a flowsheet of a supercritical steam cycle. The performance optimisation of the amine plant takes into account integration with the power cycle and the compression train. This allows favourable trade-offs between changes in steam extracted from the power cycle and compression power to be identified, as illustrated in Figure 1.

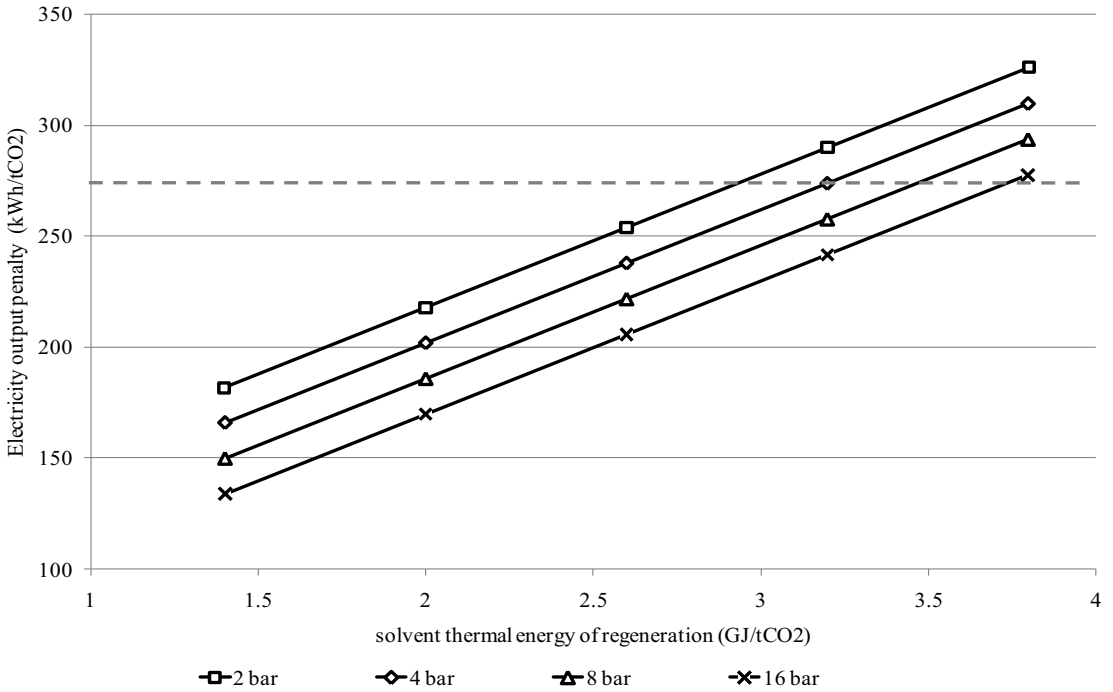


Figure 1: Illustration of trade-offs between solvent energy of regeneration and desorber pressure for the assessment of the overall electricity output penalty (EOP) of a capture and compression process thermodynamically integrated with the power cycle of a coal plant. The horizontal reference line is for an EOP of 275 kWh/tCO2 with a desorber pressure of 2 bar, a solvent energy of regeneration of 3.2 GJ/tCO2 and ancillary power for the amine plant of 20 kWh/tCO2.

A rigorous thermodynamic integration of heat available from the capture and compression plants that can be used in the power cycle has been conducted, for a range of different solvents with a temperature of regeneration varying from 90ºC to 170ºC and an energy of regeneration varying from 1.4 GJ/tCO2 to 3.8 GJ/tCO2. The results are presented here using a correlation developed by some of the authors in [4], which relates the overall EOP of the capture process to three key process parameters: solvent energy of regeneration, solvent regeneration temperature and desorber pressure. This correlation is accurate to within 0.5% for the EOP of steam extraction and within 3% for the EOP of compression for new-build plants for which the steam cycle and the compression train are purposely built to minimise the EOP based on the process parameters of the amine plant. It is used here for part b) of the analysis, whilst a dedicated steam cycle and compression model is used for part a) in order to match the requirements of the reference solvent. It is then re-used in part c) to identify performance lock-in.

The amine plant is modelled using an in-house rate-based model for the absorption and desorption columns based on the two-film theory to determine the overall mass transfer coefficient at gas/liquid interface. The rate-based model is

incorporated into a standard flowsheet with a cross-heat exchanger between the absorber and the stripper, a cooler for the lean solvent at the absorber inlet. A flash tank has been specifically added at the stripper inlet.

5. Sensitivity analysis of solvent properties and identification of lock-in

5.1 Sensitivity to solvent specific heat capacity

Changes in solvent specific heat capacity modify the sensible heat contribution to solvent energy of regeneration. This results in changes in the amount of steam extracted from the turbines and, by extension, relates to the power plant's capacity to utilise additional steam available for power generation and export additional power if needed. For this analysis the work of Cheng et al. [5] has been used to provide a correlation predicting the specific heat capacity of a 30%wt MEA solution based on the solution weight fraction, the temperature and the specific heat capacity of both water and pure MEA. A factor is added in this work to multiply the solvent heat capacity for the purpose of this analysis, as shown below

$$Cp_{solvent} = (1+\alpha) * [\ (1-X) * Cp_{H2O} + X * Cp_{MEA} + X * (1-X) * (a + b * T + c * X/ T)\ ]$$

$Cp_{solvent}$	J/kg/K	Solvent specific heat capacity	T	ºC	Temperature
Cp_{H2O}	J/kg/K	Specific heat capacity of water	X	-	Solution weight fraction
Cp_{MEA}	J/kg/K	Specific heat capacity of pure MEA	α	-	Parameter for sensitivity analysis
a,b,c	-	Parameters from Cheng et al [5]			

The electricity output penalty for the reference solvent is shown in Figure 2 as a function of the lean loading at the absorber inlet along with four hypothetical solvents with a heat capacity varying from 70% to 130% (α from -30% to 30%) of the heat capacity of the reference solvent. Figure 2 shows that the optimum lean loading is a function of solvent heat capacity and that solvents with a lower heat capacity tend to have a higher optimal lean loading. They are also prone to the development of a temperature bulge in the absorber at low lean loading (0.31mol/mol in this example). This is detrimental to the EOP since solvent flow rate then needs to be increased to maintain a given target removal rate. It is worth noting that the optimum lean loading reported here does not coincide with the lean loading which minimises solvent energy of regeneration, since compression power requirements and other aspects of integration also have to be taken into account.

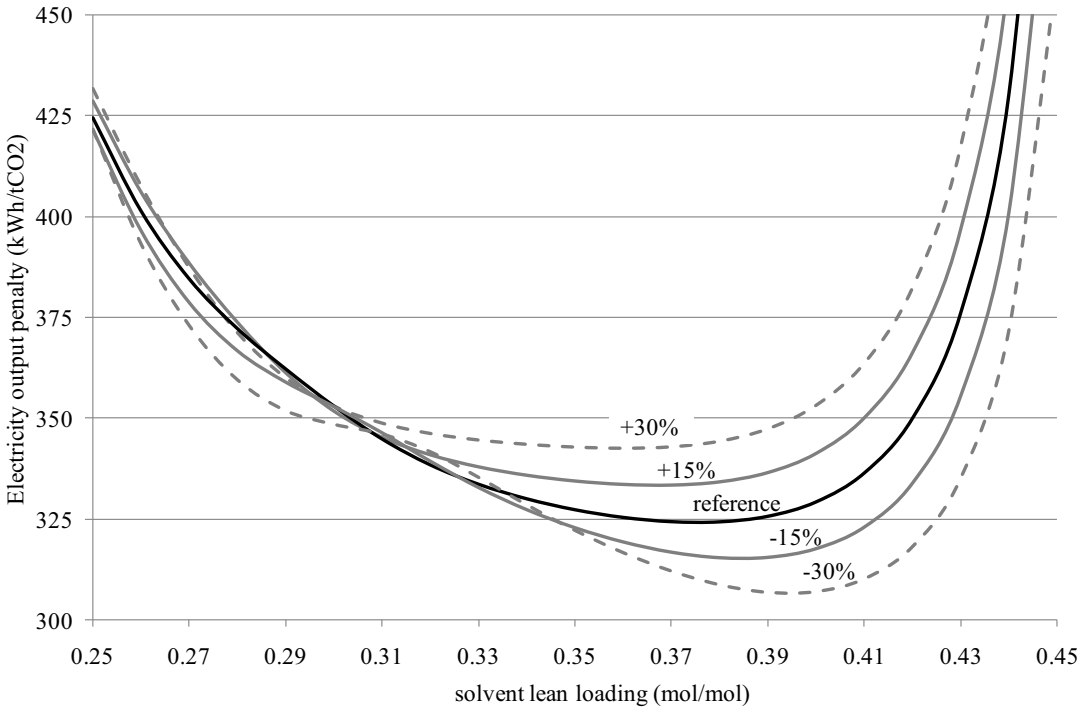


Figure 2: Overall electricity output penalty for changes in solvent specific heat capacity. Reference Solvent is 30% wt MEA

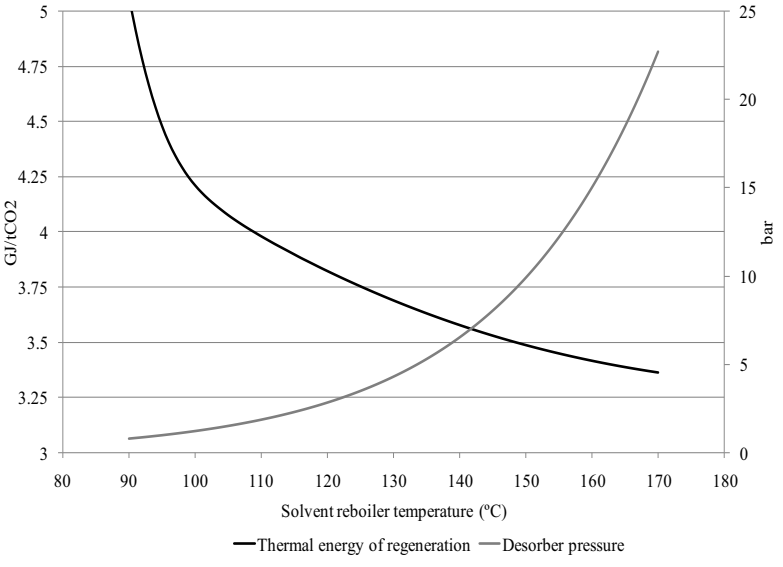
Power plants which are sized for base-load operation with their initial solvent, e.g. the reference plant of a), are at risk of technological lock-in since, because they are not capable of generating additional electricity with the steam that is no longer used for solvent regeneration, they do not have the capacity to use solvents with a lower heat capacity. The difference in EOP between the reference solvent – their design EOP – and the EOP of Figure 2 for solvents with a lower heat capacity represents the possible performance lock-in faced by utilities.

This risk can be mitigated by fitting capture on an existing unit, which inherently will have spare LP turbine and generator capacity when capture is added, or by oversizing these components for a new-build plant. Steam consumption issues for capture-ready plants steam cycle options that avoid committing the plant owner to a specific solvent, are discussed in [6].

5.2 Sensitivity to solvent thermal stability

For this part of the analysis the allowable temperature for acceptable solvent thermal stability is varied from 90ºC to 170ºC whilst the remaining solvent properties are kept identical to the 30%wt MEA reference solvent. Solvent energy of regeneration, desorber pressure and the overall EOP and its contribution are illustrated in Figure 3.

At 170º the desorber pressure is well above 20 bar, and so is the compressor inlet pressure (with pressure drops taken into account). In these circumstances, when an improved solvent with a higher temperature of regeneration is used then the risk of performance lock-in comes from several parts of the process. First, the desorber vessel must be able to cope with the increased pressure. The compression train needs to be able to accommodate a higher inlet pressure and also a reduced pressure ratio while the CO_2 mass flow remains constant. Finally, the steam cycle must be able to provide large amount of steam at a temperature higher than it was designed for. This is discussed for capture-ready coal and gas plants in more detail in [6].



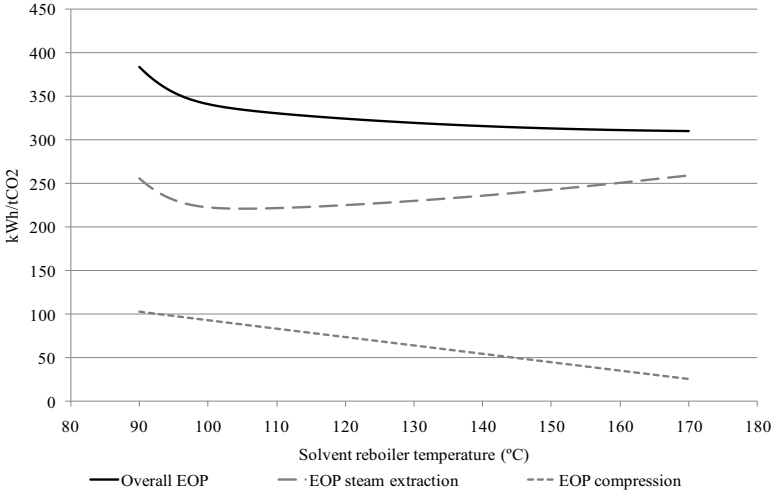


Figure 3: Solvent energy of regeneration and desorber pressure (top L) and electricity output penalty (bottom L) for a range of solvent reboiler temperatures. Lean loading is 0.38 mol/mol. EOP of amine plant is constant at 20 kWh/tCO_2

Solvents with lower temperature of regeneration and favourable heat capacity and vapour-liquid equilibrium may also reduce the overall EOP. In this case the compression train needs to cope with a larger pressure ratio at a constant mass flow. Provided that the desorber pressure stays above atmospheric no structural reinforcements are needed, but they could be necessary at pressures below atmospheric. Unlike the previous case, the steam cycle is, however, likely to be able to provide steam at a lower temperature. The steam extracted can be throttled down to a lower pressure, or alternatively expanded into an additional back-pressure turbine if economically justified. Consideration of the LP turbine is also critical to avoid unnecessary valve losses.

6. Upgradability economics

As discussed in Section 2, two distinct rationales for upgrading the capture technology used in a CCS power plant are considered in this study. A legislative driver for upgrade (2.1) implies the option either to upgrade, or to cease, or significantly reduce, production. The power plant operator must evaluate whether the anticipated revenue for continued life of the plant after upgrade is worth the investment necessary to gain a continued licence to operate. Extensions of residual plant life times may be a consideration in this circumstance, so that an economically-viable operating life can be obtained for the upgraded capture technology. Although existing base power plants are typically valuable assets, there may be cases where the most economically attractive option is simply to cease operation.

A power plant upgrade could also be justified by an economic driver, particularly if the option to export additional power is available. When an improved solvent becomes commercially available utilities with a future-proofed asset can upgrade the solvent to generate additional net revenue, or do nothing and keep running, possibly with reduced hours, when the plant changes rank in the merit order.

Regardless of the driver for upgrading CCS technology, changes in net short run cash flow (i.e. cash available to pay back capital investment and/or as long-run profit once income and short run costs have been considered) can be considered to come from two differences between an upgraded and non-upgraded plant: (1) a change in short run marginal cost (SRMC) and (2) a change in operating hours as a result of this reduced SRMC. The first contribution is given by:

$$\delta_1 = \Delta\text{SRMC} * \text{Op hours}_0 * \Delta\text{MW}$$

δ_1	£	First contribution to change in net short run cash flow
ΔSRMC	£/MWh	Difference in short-run marginal cost between the initial and the upgraded plants
Op hours$_0$	hr	Number of operating hours of the initial plant
ΔMW	MW	Difference in power output between the initial and the upgraded plants

Figure 4 illustrates a case where the SRMC of an initial plant, $SRMC_0$, is reduced to a value $SRMC_1$ by a solvent upgrade and δ_1 can be quantified by the grey shaded area.

The second contribution to the net short run cash flow is more difficult to quantify precisely since it is dependent on the electricity market where the plant is operating, and in particular on the SRMC and the number of operating hours of the next plant in the merit order. It is, however, limited by the difference in SRMC and in operating hours between the initial plant and the upgraded plant, since the selling price for electricity from the upgraded plant must be less than the SRMC of the plant if it had not been upgraded. If it were any higher than this then both plants would be operating.

The second contribution can thus be approximated as follows:

$$\delta_2 < \Delta\text{SRMC} * \Delta\text{Op hours} * \Delta\text{MW}$$

δ_2	£	Second contribution to change in net short run cash flow
ΔSRMC	£/MWh	Difference in short-run marginal cost between the initial and the upgraded plants
ΔOp hours	hr	Difference in operating hours between the initial and the upgraded plants
ΔMW	MW	Difference in power output between the initial and the upgraded plants

Whether or not this extra revenue is significant is a function of the magnitude of ΔSRMC, as well as electricity market fluctuations in the period when an upgraded plant would operate but a non-upgraded plant would not operate. This suggests that a full economic evaluation of a potential upgrade requires consideration of a wide range of commercial and legislative aspects, including market analysis to establish likely power plant load factors and electricity prices.

Once the expected change in short run net cash flow associated with having an upgraded plant has been determined, this can be compared to the fixed costs (especially capital expenditure) associated with future proofing for upgradability. It is important to note that the value of being able to upgrade in the future is inherently uncertain. When looking forward from initial capital expenditure during construction, the potential benefits and costs are a function of several factors including: changes in revenue due to upgrade, year of upgrade (due to the discount rate of money over time, possible changes in capital costs as technology changes with time) and also the plant lifetime left to benefit from the upgrade. A robust exploration of economic performance of the value of future-proofing CCS power plants is, therefore, likely to require that probabilistic (e.g. Monte Carlo) analysis is carried out.

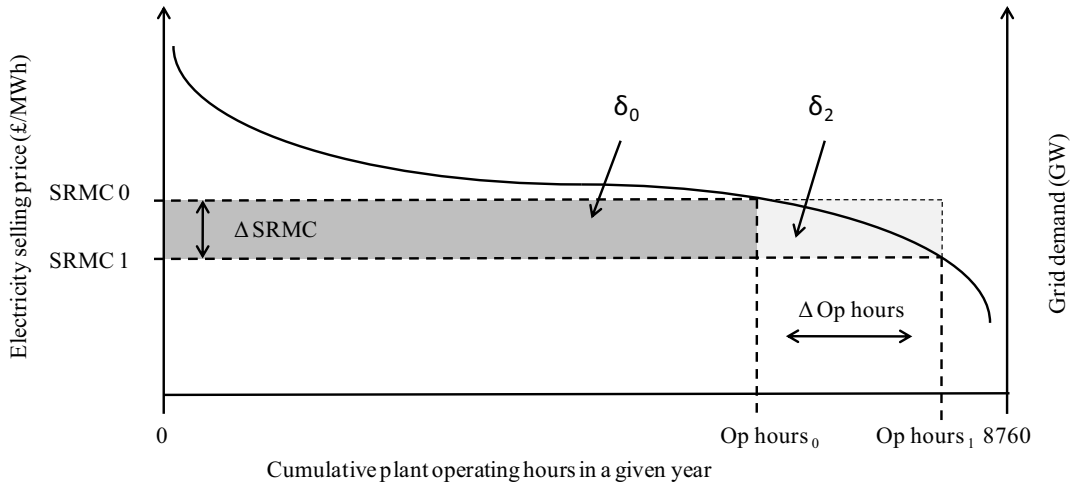


Figure 4: Illustrative cumulative annual electricity wholesale prices for original (0) and upgraded (1) CCS plant

7. Conclusions

Whilst CCS is in a demonstration phase utilities will face a period with fast learning curves for capture technologies, with costs expected to decrease and improved solvents for post-combustion capture likely to become commercially available after the first CCS plants have started operating. In addition, regulatory changes may also impose the use of higher capture levels and/or more environmentally friendly solvents than current amines after some initial demonstration period for CCS.

Coal and gas plants with post-combustion capture can be future-proofed against these potential changes and so will be able keep their license to operate by securing compliance with stricter environmental legislation, or be able to improve their economics, if they can be designed to accommodate potential future solvents and be capable of coping with a broad range of solvent properties. Critical aspects of the capture equipment for which consideration needs to be given in order to make an upgrade with a possible improved solvent are: the absorber column dimensions, the compression suction pressure, the steam turbine's ability to supply the required steam flow and temperature and the limitations on the desorber operating pressure. A full economic evaluation of a potential upgrade requires consideration of a wide range of commercial and legislative aspects. Electricity market analysis is also needed to determine both power plant load factors and electricity prices, which are critical to determine the potential changes in net cash flow of a solvent upgrade. All of these issues are addressed in more detail in a forthcoming report commissioned by the IEAGHG programme [2].

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